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PERFORMANCE IMPROVEMENT OF GEYSERS POWER PLANT UNITS 9 & 10

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ABSTRACT

The performance of Geysers Power Plant Units 9 & 10 deteriorated due to the effects of age, increasing undesirable steam constituents, and the introduction of continuous H_2S abatement systems. In the ongoing process of trying to reverse this trend and keep the units operating at their full potential, several projects were implemented prior to and during the 1988 unit overhauls. The performance is measured by capacity (% of design generation) and efficiency of steam use (steam rate in lb/kwhr). The capacity was improved from 71.4% to 98.6% and the steam rate was reduced from 20.0 lb/kwhr to 16.3 lb/kwhr. The improvements were aimed at minimizing non-generating steam use, eliminating curtailments due to exhaust and first stage pressure limitations and reducing lost generation due to redundant mechanical failures.

BACKGROUND

The Geysers Power Plant, located 26 miles northeast of Healdsburg, California, is owned and operated by Pacific Gas and Electric Company. The privately owned land is leased by several steam suppliers. Units 9 & 10 are two of six nearly identical geothermal units supplied with steam from UNOCAL. Each unit consists of a Toshiba 55 MW turbine-generator operating with design inlet conditions of 113.7 psia and 355 °F exhausting to a 4 in. Hg direct contact condenser. The mixture of the cooling water and condensate is pumped from the condenser to the cooling tower where approximately 70% of the condensate is evaporated and the rest is reinjected into the steam field. The cooled water is drawn from the cooling tower basin to the distribution trays of the condenser by condenser vacuum. When Units 9 & 10 came into commercial operation in 1973, H_2S contained in the steam was allowed to exhaust out the cooling tower stacks. In 1984, the units were required to install continuous H_2S abatement systems. The abatement system retrofit to the units caused the cooling water system to degrade. When the project began, the units were each normally curtailed at least 10 MW due to cooling problems and mineral deposit plugging of the steam path. In addition, the unit history records revealed substantial generation losses from redundant mechanical failures.

MINIMIZING NON-GENERATING STEAM USE

Interstage Drain Size Reduction

In 1971 when the first unit of this type came down for its two month inspection, severe erosion was found on the turbine blades and diaphragms. Toshiba eliminated the erosion by retrofitting the unit with drains to remove interstage condensation. The interstage drain modification was incorporated in the design of subsequent units. The 1" drains allowed almost 80,000 lb/hr of steam to exhaust various stages of the turbine without being fully utilized. Records indicate that before the drains were installed the steam rate was close to design, after the installation it increased by 1.4 lb/kwhr. In 1985, the first and second stage interstage drains were routed outside of the condenser to a drip pot then back to the condenser in order to remove condensate but eliminate exhausting steam. A level was maintained in the drip pot by throttling a manual valve on the drip pot outlet pipe. The modification seemed to improve back pressure slightly, but it was difficult to maintain the drip pot level due to fluctuations in main steam and condenser pressure. The project was abandoned because the improvement did not justify the expense of the elaborate piping and automated level control that would be required. The modification was useful, however, in monitoring how much condensate was forming. Based on the condensate formation rate, the interstage drains could have been 1/16" and still removed the condensate and some steam. Drains that small would undoubtably plug with mineral deposits so the drains were resized to 1/2". The steam rate improved 3.0% or 0.5 lb/kwhr due to this modification.

Rotor Tip Seals

The clearance between the turbine blade tips and the diaphragm was 0.200 inch. Blade tip fin seals were installed to reduce that clearance to 0.060 inch in order to reduce the blade tip leakage. The modification improved the steam rate an estimated 0.6 lb/kwhr or 3.5%. The values for the steam rate improvement due to the interstage drain reducers and tip seals presented here are those predicted by the manufacturer, Toshiba. While the total improvement of both modifications was measured to be 6.5%, it was impossible to tell the individual contributions since the modifications were done at the same time.

Steam Jet Gas Ejector Capacity Reduction

When Units 9&10 were placed into commercial operation, it was discovered that the noncondensible gas flow was 10% of the predicted value. The ejectors are designed to draw a fixed amount of noncondensibles. If there is not adequate gas loading, they draw condenser vapors. While this did not directly cause increased back pressure, the extra motive steam the oversized ejectors used had to be condensed by cooling water that could have been used by the main condenser. In 1987 one of the two 1st stage ejectors was experimentally blanked off. Steam use was reduced 11,050 lb/hr and the water formerly used to cool the motive steam was routed to the condenser. The back pressure dropped 0.8 in. hg. During the 1988 overhauls, the second stage ejector was replaced to match the capacity of the first stage ejector. The steam use dropped another 18,300 lb/hr.

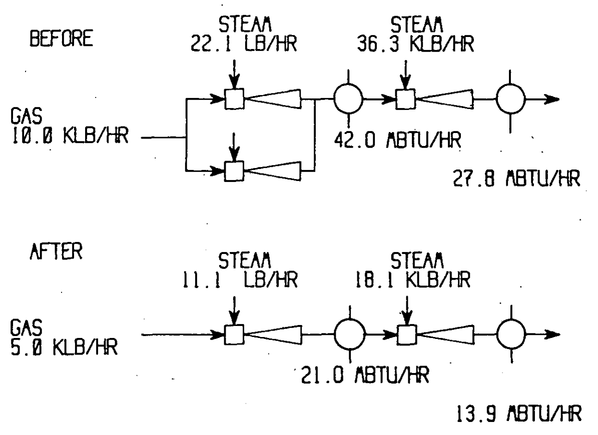
Shortly after the units returned from overhaul they began to experience curtailments due to insufficient steam supply. If the ejector modification is evaluated as a capacity improvement (since the motive steam that was saved could be used to maximize generation) the 29,350 lb/hr saved could generate almost 2 MW per unit. This modification is illustrated in figure 1.

EXHAUST PRESSURE CURTAILMENT

Elimination of Condensate Recirculation

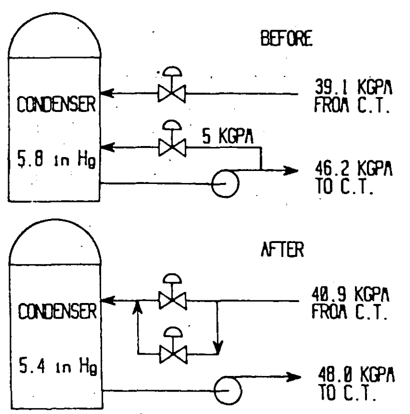
Another problem found during initial unit start-up was that the movements of the 36" condenser cooling water inlet valve were too crude to control condenser level. In order to fine tune the control, condensate pump discharge was recirculated back to the condenser. At the onset of this project the flow to the condenser was typically 10% to 25% below design. This was partially due to the condensate recirculation and partially due to the existence of the abatement residue in the water.

FIGURE 1



The hot water recirculation line was eliminated. The condenser level control is now fine tuned with a bypass around the condenser cold water inlet valve (See figure 2). The steam rate decreased 0.9 lb/kwhr when the unit changed to this level control system.

FIGURE 2



Maximizing Circulating Water Flow

When the regulatory agencies made hydrogen sulfide abatement mandatory in 1984, the units were retrofit with the only economically feasible abatement process available for a unit with a direct contact condenser. Chemicals are added to the circulating water that oxidize the hydrogen sulfide to elemental sulfur in the condensate/circulating water system. The sulfur suspended in the circulating water system adheres to any surfaces it contacts including the circulating water pump internals. The pump performance would degrade until vibration was induced from an uneven accumulation of mud on the impeller or because the pump flow was so low they were running out too far on their performance curve. Alternate abatement processes such as an incinerator that would eliminate much of the silt were evaluated as part of this project, but were not found to be economically feasible. To try and minimize the silt problem, larger pump impellers were installed to offset the inadequate flow and a sparger ring was designed that cleans the suction screens and impeller on line. Also, various dispersants were tried until one that satisfactorily keeps the silt in suspension was found.

Cooling Tower Capability

By the time of the 1988 overhauls, the capability of the cooling towers had degraded to 50% of design and generation was down to less than 45 MW due to high back pressure. The cooling towers were gutted and repaired structurally, then upgraded fill, drift eliminators, fans, and distribution piping were installed. A wetting system was designed and installed that rests in the distribution trays. It not only provides wetting when the cooling tower is out of service, but the nozzles are orientated such that they can be activated during operation to break up accumulations of silt in the distribution trays. Unit 10 returned to service on a 68 °F wet bulb day generating 59 MW with a 4.1 in. Hg exhaust pressure.

FIRST STAGE PRESSURE CURTAILMENT

Turbine Waterwash

All units at the Geysers are prone to turbine steam path mineral plugging. The mineral plugging lowers the steam rate by changing the geometry of the blades and lowers the capacity by curtailing generation due to first stage pressure limitations. The minerals have an affinity for the liquid phase. The superheated steam reduces to 100% quality in the first stage of the turbine so that is where the plugging is the greatest. If the steam is desuperheated prior to entry to the turbine, the minerals can be removed in the separator and 90% of the deposits are prevented. The loss of energy due to desuperheating the steam costs the plant about 2% load. If deposits still manage to form, they are removed by injecting enough additional condensate downstream of the separator to bring the quality down to 99%. This "waterwash" costs the plant 3% load.

For the Geyser units with tube and shell type condensers, the pure condensate from the condenser hotwell is an excellent source of desuperheat water. For units with direct contact condensers like 9 & 10, there is not a pure source of condensate to inject into the steam so continually desuperheating requires piping condensate from a nearby tube and shell type condensing unit. Units 9 & 10 did not have an accessible source of condensate nearby, so water from a spring was made available to take the steam from superheated down to 99% quality when necessary to remove accumulated deposits. The overall cost in plant load is less with this method, but the risk of turbine damage is greater, so this method is used only when necessary.

REDUNDANT MECHANICAL FAILURES

Underground Pipe

The 42" and 48" underground circulating water pipe and the cooling tower distribution pipe was made of "Techite". Techite is not helically wound like fiberglass pipe found on the market today. The pipe had experienced three failures by 1986, splitting cleanly around the circumference and sending 50,000 gpm of geothermal condensate into the unit yard. The costs of excavating, repairing the pipe, and losing two weeks of generation each occurrence easily justified replacing the entire system with fiberglass reinforced plastic pipe.

Cooling Tower Fans Motors

The cooling tower motors were mounted in the fan stacks directly under the fans. The corrosive, damp environment would accelerate motor failures. In order to remove the motor for repair, the fan, gear box, and motor would have to be removed with a crane. Over 20,000 MWhr had been lost due to cooling tower fan motor failure in the year proceeding the overhaul. New gear boxes were installed with right angle gear drives so the motors could be located outside of the stack. Graphite shafts were installed to resist corrosion and the fans were replaced with higher efficiency fans.

SUMMARY

When the project was complete, the steam rate for Units 9 & 10 had decreased from over 20.0 lb/kwhr to 16.3 lb/kwhr. Reducing the inter-stage drains and installing tip seals improved the steam rate 1.1 lb/kwhr. Down-sizing the gas ejectors increased capacity by 2 MW. Elimination of the condensate recirculation as a means of condenser level control lowered the steam rate 0.9 lb/kwhr and additional efforts to maximize circulating water were successful. The cooling tower repair work eliminated curtailments due to the 6.0 in. Hg turbine exhaust pressure limit and the turbine waterwash was installed to eliminate first stage pressure curtailments. The underground pipe was replaced and the cooling tower fan motors were moved outside of the stack which eliminated almost 40,000 MWhrs annually of lost generation. The capacity increased from 71.4% to 98.6%.